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Subject: Comments on the Draft Guidance for Transition from Class II to Class VI
Sent Via e-mail to GSRuleGuidanceComments@epa.gov

These comments are submitted by Dr. Susan Hovorka with input of several researchers at the Gulf Coast Carbon Center, Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin. Our expertise comes from monitoring and monitoring design at seven field tests of geologic sequestration, under funding from the US DOE National Energy Technology Laboratory. These tests involve CO_2 EOR as well as saline formations associated with oilfields, and settings ranging from no production to pre-production to active production. Our comments therefor are grounded in experience and from an academic perspective. Our comments focus on technical issues and do not comment on policy and regulatory problems within the Draft Guidance.

The Draft Guidance does not correctly describe the differences between CO_2 injection for the tertiary recovery of oil or natural gas (ER) and CO_2 injected for geologic storage (GS). Model examples are not correctly constructed to show the difference between the two activites. Operators and regulators following this guidance may therefore either 1) fail to provide protection to USDW from changes that occur during transition from ER to GS or 2) may interfere with or impede injection for EOR by instituting requirements that are not essential to protect USDW from endangerment.

The Draft Guidance lists on page 16 the eight factors identified by 40 CFR 144.19(b) that may indicate a change in project operations that may increase risks to USDWs. The Draft Guidance correctly specifies "no single factor from this list should be independently relied upon to make determinations. Rather, all available factors should be considered in determining the appropriate well class for a carbon dioxide injection well…" However errors in the background information (p. 9-15) combine with errors in the sections describing each factor (p, 18-30) to cause the Draft Guidance to fail to provide proper guidance regarding how to determine whether an increased risk to USDWs warrants re-permitting a project from Class II to Class VI.

One major error is shown in figure 4 and the models in box 1 and box 2, where transition from ER to GS is marked by pressure increase at the injection well. This condition will be valid in only a subset of such transitions and cannot be relied upon to be protective of USDW. Further, such an assumption may impede commercial EOR operations under normal Class II conditions, in which such variation in pressure is needed for oil recovery and managed by Class II.

The case that a pressure trigger is not adequate for USDW protection is made in this paragraph. Many reservoirs that would be attractive for GS are thick formations with high permeability and good water drive (open reservoir boundary conditions) so that varying injection rate and decrease in production has only a small impact on reservoir pressure. Such minimal pressure response is observed at the large scale Sleipner injection conducted by Statoil in the North Sea where about 1 million metric tons per year are injected for GS. Similar modest responses are known from high permeability regional formations in the US, for example in the Frio or Miocene formations of Texas. However, at GS sites (no production) with minimal pressure elevation, USWD protection would not be achieved under class II with ¼ mile AOR; the CO_2 plume would become large triggering a Class VI approach. The high pressure increase shown in figure 4 and box 1 are characteristic of thin or low permeability reservoirs or closed boundary conditions; such settings are poor choices for GS because the rapid pressure increase would cause the site to approach the geomechanical limits of reservoir or seal (e.g. fracture initiation pressure).

The case that a pressure trigger would interfere with oil production is made in this paragraph. During secondary and tertiary recovery, episodes of pressure increase are needed. In particular, at the start of EOR, the pressure in the reservoir is increased to approach conditions of miscibility of CO_2 and oil. Pressure is increased by injection of either (or both) CO_2 and water; however water injection is not managed under class VI. The pressure equals risk approach presented by the Draft Guidance would interfere with normal EOR operations that have been managed safely under class II.

The approach needed in the guidance is to properly combine the eight factors identified by 40 CFR 144.19(b) to show how operators and regulators can simply and robustly identify a change in project operations that may increase risks to USDWs. Class II regulations are designed for conditions when the *area of the plume and area of elevated pressure are controlled by production*. In EOR, injectors and producers are arranged in patterns such that the injected CO_2 and mobilized oil are captured by surrounding producers. No large CO_2 plume is created and continued injection processes the reservoir within the pattern. The producers act also as pressure sinks so that the area of elevated pressure does not propagate far beyond the active patterns. Active management by production is the reason that class II is protective with a ¼ mile (or other small) AoR.

EOR operators create a balanced flood by calculating injection/withdrawal ratio (IWR). Note that all injection (CO_2 and water) and all withdrawal (CO_2, water, oil, other gas) are included in the balance. Operators typically change many aspects of the balance to optimize the commercial operation, however as long as production dominates, the Class II AoR is protective. The operator may change the volumes, composition, and ratios of injection fluids and the operating pressure, and in a situation where the production is used to manage the area of pressure and fluid, Class II rules are protective.

The indicator that Class II rules may not be sufficiently protective is that if the area of the plume and area of elevated pressure are *not* controlled by production. Without control by production, injected fluids and oil may migrate outside of the patterns and beyond the class II AoR. In conditions where the pressure is elevated, lack of control by production will increase the *area* of elevated pressure. A lack of control by production may allow CO_2 or high pressure brine to migrate into areas with wells that have not been assessed or to overfill the trap.

The guidance needs to be improved so that it shows how factors from the list of eight factors identified by 40 CFR 144.19(b) are combined to provide a clear indicator that the larger AoR and other assessment from Class VI are needed to provide protection of USDW. A proper IWR calculation can be an indicator, however carefully constructed examples appropriate to the cases where transition might be considered are needed so that the guidance does not interfere with oil and gas production.

This list of eight factors needs refinement in the guidance to show how to separate normal ER from storage that requires Class VI regulation. Many subsets of the bulleted list are normal occurrence for stages of EOR, for example increase of reservoir pressure (during early stages of an EOR project), increase in CO_2 injection rates (field wide increase during maturation of a project as patterns are added and recycle increases), decrease in production rates (of oil, always during maturation of an EOR flood, but may be balanced by increased water production), anticipated recovery of CO_2 at cessation of injection (CO_2 is often moved around in a pattern flood from older to newer patterns). Additional work is needed to create protocols that separate EGR and EOR and deliberately and quantitatively input scenarios for a change in operations from a production-dominated case to a storage dominated case. The Draft Guidance as written adds to concern that EPA will capriciously interfere with EOR (and possible future EGR).

The Draft Guidance is made less technically correct because it comingles EOR, which is a mature technology, with EGR, which has not been deployed commercially and therefore operation is hypothetical. If CO_2 was injected to produce gas, the mechanism would have to be different from oil production. During oil production, the design is for the CO_2 to contact the oil and become miscible, and separation is relatively low cost because CO_2 comes out of solution in oil efficiently with pressure drop. In contrast, CO_2 is a quality-degrading contaminant to gas that has to be separated through chemical processes, therefor most proposals for enhanced gas production attempt to isolate the CO_2 from the methane in the reservoir. Production wells do not control the development of the plume in EGR. However, risk to USDW an EGR site is likely low because a gas field typically has few wells and the use of EGR is usually conceptualized is to elevate reservoir pressure in a reservoir that has stopped production because it is depressurized, meaning that it is a hydrologically closed structure.

The attached list provides detailed line-by-line comments.

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Line-by-line comments

Page and paragraph	Guidance statement	Recommended revision	Discussion
p. ii para 4	EPA recognizes that it is very likely that some carbon dioxide will be trapped in the subsurface as part of ER operations	Carbon dioxide can be stored during Class II injections	This statement is misleading. Large amounts of CO_2 are trapped during EOR; this has been clearly documented by numerous observations
p. iii, para 1	are tailored to the longer timeframes and greater injection volumes expected at GS operations.	are tailored to large CO_2 plumes and large areas of elevated pressure	This statement is misleading, as EOR projects accept larger amounts of CO_2 and have retained it longer than any current GS projects and at volumes and durations equivalent to planned projects.
p. 1, para 3	EPA recognizes that it is very likely that some carbon dioxide will be trapped in the subsurface as part of ER operations however, if there is no increased risk to USDWs, then these operations would continue to be permitted under Class II requirements.	Carbon dioxide injected as part of ER operations will continue to be permitted under Class II requirements.	This statement is illogical as it suggests that trapping CO_2 is in some way more of a risk to USDW than injecting CO_2.
p. 2 para 2.	reservoir pressure conditions and injection rates and volumes will be different between Class II and Class VI."	Revise approach	This statement is not logical or justified. Reservoir pressure would be limited by fracture pressure under both operations, and injection rates and volumes limited by tubing diameter and reservoir injectivity. Two things would systematically change if a field was converted from EOR to GS: patterns of injectors and producers would be changed to eliminate producers and any water injection would stop.
p. 2 para 2.	The corrosively of carbon dioxide in the presence of water necessitates additional protective measures that are not	Remove	This statement is not logical or justified. EOR involves abundant corrosive CO_2 – brine mixtures (some places

	required of Class II owners or operators."		with H2S), so Class II has the need and experience with corrosion inhibition. Cession of production and cessation of water injection at the end of EOR will reduce well corrosion risk.
p. 3, para 1	EPA anticipates that the injection pressures and injected carbon dioxide volumes will be greater for commercial-scale GS projects than for ER projects, resulting in larger project areas, increased project duration, and, therefore, a greater potential for risk of endangerment to USDWs	Revise approach	This anticipation is not grounded in experience. The reason that the project area is larger for GS is that producers do not control the plume size and the area of pressure elevation. With EOR having 40 year duration and still going strong, the justification for expectation longer duration of GS is not clear. The reverse might be true, that GS projects may fill and injection wells be plugged and abandoned to move storage operations to fresh areas while projects with extraction continue, for example see project life estimations of Jain (2011).
p. 5. Table 1, 4th box.	Post-injection site care and site closure None.	Replace "none" with "liability remains"	Class II does not require PISC, however it is important to note that liability remains and has been used to force responsible parties to fund clean-up if damages are discovered decades after closure.
p. 9.	ER, which includes both EOR and EGR	Add consideration of EGR throughout.	This section mentions but then does not discuss EGR. Sources of information about ERG include the Dutch project K-12 B, British Geologic Survey and other US work on North sea gas field, and preliminary scoping by WESTCARB for a planned RCSP project at Rosetta (never executed). Cushion

			gas literature may be helpful also.
p. 11, Figure 2.		Remove figure or update and make relevance clear	Figure out of date; more current figures available. Why is this presented in guidance?
p. 11, para 1.	Immiscible displacement occurs at shallower depths and lower pressures than miscible displacement	Immiscible displacement occurs at shallower depths or lower pressures, or in heavier oils than miscible displacement.	Complexities of miscibility are not presented and concept is not very relevant to the guidance.
P. 11, para. 1	is compressed to a supercritical state	is compressed to a dense phase	CO_2 is compressed to dense phase, typically liquid because of surface temperature, prior to entering the pipeline so that it can be pumped. Liquid or gaseous CO_2 at surface becomes supercritical in the injection well if the pressure and temperature are sufficiently high. A few injections take place in liquid or gas phase. It doesn't matter for permitting.
P. 11. Para 1.	Production wells in the vicinity of the carbon dioxide injection well extract a fluid mixture that may contain injection fluids (e.g., carbon dioxide, water) and formation fluids (e.g., water, oil, solids and natural gas).	Add discussion of patterns and how they control plumes	It is important here to explain in some detail about pattern floods, and how arrangements of injectors and producers are optimized to push and pull CO_2 to contact with oil and then move to the producers. Pattern design is the essence of the class II control that justifies protection of USDW with a small AOR.
p. 12 para. 2	After mixing delivered carbon dioxide and recycled carbon dioxide, the injectate composition may vary from 92 percent to 97 percent carbon dioxide."	After mixing delivered carbon dioxide and recycled carbon dioxide, the injectate composition is variable containing methane, hydrocarbon, or H2S impurities, which may be removed at the operator's discretion	These limits are too small, recyle composition is operator's choice.
p. 12 para 3.	EOR fields are normally operated with WAG injection".	Many EOR fields are operated with WAG injection".	WAG is not universal

P, 12, para 3,	Carbon dioxide injection wells and oil production wells are sited in patterns frequently repeated throughout the site, designed to maximize oil recovery.	Add information about how patterns control the reservoir response to injection	This explanation is insufficient because of the importance of production in managing risk during EOR. Should have several references and a map with flow lines.
p. 13. Bullet list.		Add hydrocarbons	Missing is hydrocarbons and associated materials which are known risks to USDW. This is important in context of EOR.
p. 13. Bullet 1 and 3.	lead and arsenic	Remove example	lead and arsenic are not good examples of substances known to be released by CO_2 -rock-water interaction. Numerous field tests have shown that these are not examples of contaminants released (see summery of Yang and others, 2014).
p. 13. Bullet 2.	mercury	Remove example	Mercury is not a good example of a post-capture impurity, as it is not left in the CO_2 stream after capture
P. 15 figure 4.		Completely rethink figure using available quantitative information.	This is a poorly thought though and unjustified figure. It lacks proper conceptualization of both risk to USDW managed under Class II as well as what might occur under GS. Without a well justified concept of risk, a risk-based approach to regulation will fail to protect USDW and interfere with oil production.
p. 15, bullet list. p. 17, para 2 "	EPA recognizes that Class II wells may not necessarily transition to Class VI".	Revise section	This section is weak. The main reasons not to transition are 1) current condition, no economic value to storage of CO_2, and 2) current condition, continued increased in value of oil makes continued operation as EOR valuable.
p. 18.		Remove or make	The risk assessments

		applicable risk assessments	provided are not suitable for the purpose of the guidance. None of them deal with the scenarios that need to be assessed in transition. It is counterproductive to provide such long-non-helpful information. It would be relatively easy to model a conventional 5-spot EOR to make cases for normal EOR and for transition to storage showing concretely how to assess some likely transitions. This should be done instead.
P. 18, last paragraph.		Revise conceptual model for conversion to consider all cases to be protective to USDW and not interfere with EOR.	The injection pressure may or may or may not increase during conversion of ER to GS. If the pressure in the reservoir increases, the project is short lived, as it will reach fracture pressure and have to stop. Area of elevated pressure will likely increase, this is the signal that class II AOR is insufficient and Class VI AOR calculation and monitoring are needed.
P. 19. p. 2	Elevated pressure great enough to cause fluid movement past the confining zone or through another potential leakage pathway poses a primary risk factor to USDWs from injection	Revise approach	Class II also manages injection pressures in reservoir and numerous wells. Pressure in reservoir is not sufficient to require class VI regulation.
P. 19. p. 4.	Increase in reservoir pressure.	The response of the reservoir outside of the ¼ mile area of review is the key question, if measurements or models show that pressure in this area is elevated such that endangerment of USDW might occur, a larger AOR is needed.	Wells operated under class II undergo numerous pressure changes that are managed under class II. This guidance will interfere with oil production. “No single factor from this list should be independently relied upon to make determinations.”

			The guidance shows how to use one factor at a time and fails to show how to combine factors to separate EOR from GS.
	Specifically, increased pressures within the injection zone should be compared against the threshold pressure at which fluids are predicted to migrate from the injection zone to the lowermost USDW through a hypothetical open conduit. The pressure threshold within the injection zone that may cause fluid movement into a USDW ($P_{i,f}$) may be determined by the following equation	Revise approach	The criteria of lifting fluids to USDW would place many reservoirs with good regional artesian water drive under Class VI regulation, as reservoir fluids are naturally pressured, interfering with production. In addition, the buoyancy of hydrocarbons has to be added, which in many reservoirs would allow hydrocarbons to migrate through a flow path to USDW. The fact that this does could occur but does not is evidence of lower risk at a hydrocarbon field than a saline reservoir where such isolation has not been demonstrated. Equation 1 is misleading and should not be used in this context.
p. 20, para.1	Importantly, Eq-1 is only valid in cases where the injection zone is not overpressured relative to the lowermost USDW. Reservoirs that have been previously subjected to ER operations will, in most cases, meet this assumption.	Revise approach	In some fields, production has lowered pressure, further reducing risk, however during secondary waterflood and EOR, the pressure is increased to different extents compared to initial production. For EOR the reservoir pressure desired may be miscibility which can be significantly over initial field pressure, this is managed under class II and should not be used as a trigger for Class VI.
p.20, para 2		Revise approach	Should be revised to reflect a correct understanding of different triggers for conversion of EGR and EOR to class VI. Class II also deals with

			managing open conduits.
p.2 para. 19			The mechanism of communication between Class II regulator and Class VI regulator needs additional thought.
P. 21, Box 1.		This model should be completely revised with improved conceptualization Reservoir permeablity and boundary conditions should be described.	The set up to this problem is so odd it is difficult to determine what relevance it has. The strong pressure response suggests that the model has closed boundaries nearby and therefore is not a suitable GS reservoir. Permeability of the injection zone and boundary conditions are not specified, and these factors have a strong effect on the reservoir response to injection and withdrawal. The very close spacing of the injection-production pair, and the lack of injection/withdrawal pattern is also odd, as this is a fundamental control on the mass balance.
P. 21, Box 1.		Well completion should be specified.	The completion of the abandoned well is unclear. To create leakage to USDW it must have no or damaged surface casing. This needs to be specified. The abandoned well would be leaking oil to USDW at all conditions, as the oil will accumulate above the water column, with column height dependent on oil density. Attenuation due to presence of multiple permeable zones separating the injection zone from USDW [*Cihan et al.*, 2011; *Nordbotten et al.*, 2004; *Zeidouni*, 2012] are also neglected, so the abandoned well does have an intact long string.

P. 21, Box 1.		Set the problem up so that it is correct and reproducable	The injection rate is given in volume without specifying the fluid; from context it must be brine injection but if it is CO_2 relevant to the problem, the density of the volume must be specified to and compression dealt with correctly. In understanding the IWR and the possibility of increasing AOR for CO2 or pressure, it is important to separate injected fluids (water and CO2) and produced fluids, (water, CO_2, gas, oil).
Box 1, 2nd paragraph		Revise approach	Given 0.49 MPa in the USDW in Box 1, an initial pressure of 8.68 MPa (=0.49+(1850-1015)*9.81*0.001) in the injection zone provides hydrostatic equilibrium. In other words even a pressure difference of 8.19 MPa (=8.68-0.49) is not sufficient to initiate any leakage. It is not clear that how the guidance claims that with 6.23 MPa (=6.72-0.49) of pressure difference between the USDW and the injection zone, leakage from the storage formation to an overlying layer can be initiated.
P. 21, Box 1.		Make the problem set-up relevant to both EOR and GS conditions	The ever-increasing pressure cases show that storage will fail rather quickly after GS conditions start, as the fracture pressure will be exceeded. This shows that the model set up is not viable. Conversion from Class II to Class VI would be useful only if a viable storage project that can accept significant additional

			volumes of CO_2 results.
Page 22, last paragraph:	Pressure increases will be greatest at the injection well and decrease exponentially as distance from the injection well (*r*) increases.	Pressure increases will be greatest at the injection well and decrease *logarithmically* as distance from the injection well (*r*) increases.	The pressure change decreases logarithmically (and not exponentially) with distance based on Theis solution [*Theis*, 1935].
P. 24, para 1.	increased carbon dioxide injection rates may be used to increase the volume of carbon dioxide sequestered. Such an increase may indicate an increased risk to USDWs compared to Class II operations.	Revise approach	It is unclear how an increase in CO_2 injection rate at a properly managed Class II site would increase risk to USDW. During WAG, CO_2 injection is increased and stopped repeatedly. Based on historic data, brine provides a higher risk to USDW than CO_2. Only if the production does not control the injection does the plume size and area of elevated pressure increase.
P. 24, para 4	Production rates may be measured with a flow metering device and may be evaluated on an individual well basis or from a manifold point for a group of production wells.	Revise approach	Note that production data is usually collected on a volume basis using a test facility because of the complexities of the fluids involved. It is important to collect sufficient compositional information so that in-reservoir volumes can be estimated. Because of the large number of wells in patterns and complexity of conversions for multi-phase fluids, it is an important cost consideration that EPA not plan to do high frequency mass-balance accounting as a primary technique for triggering a change in regulatory environments.
P. 24.	Owners or operators may elect to decrease reservoir production rates to maximize carbon dioxide storage.	Revise approach	All EOR projects at first increase and then decrease in oil production over the project lifespan, but this has little relevance for protection of USDW. The operator

			has many choices in how to respond as the amount of oil production decreases, patterns are returned to water flood, (no CO_2 injected), injectors or producers are shut in, patterns changed. The scenario of Kovscek and Cakici, 2005 is a modeling based for a Stanford thesis and should not be used where it conflicts with commercial practices. The key question is if the total fluid injection and withdrawn causes increase in CO_2 plume size or area of elevated pressure such that Class II is not protective.
p. 24-last para and page 25. Para 1:	Declining production rates (of all fluids) and reservoir injection rates (all fluids) are steady or increasing for an extended period of time is a top ranked indicator for both EOR and EGR that assessment may be needed to determine if a Class VI permit is required.		This statement should be made earlier. The definition of "extended period" must be calculated, it depends on reservoir thickness and area, starting pressure, boundary conditions. Note that the EOR is started with a filling period, which water or CO_2 or both are injected without production, so that miscibility is approached. Filling to prepare for EOR for more than a year is common for large depleted fields. The operator will have calculated the time period to not push oil or CO_2 out of the trap, the regulator can repeat this calculation for similar reasons. Then the reservoir is operated in a balance with injection and withdrawal (all fluids) equivalent. Note that high injection rates may use water or other fluids not

			regulated under Class VI.
P. 26 Box 2.	Figure 7. Graph of Predicted Change in Reservoir Pressure for Scenario 2 (see Box 1), with a Decrease in Reservoir Production Rate at 360 Days.	Revise approach, use open boundary conditions, document needed model parameters so example can be reproduced.	This figure has the same flaws as box 1, in that characteristics on which it is based are not constrained. Boundary conditions and permeability are needed.
P. 26 Box 2.		Specify case for closed boundary conditions.	For a closed-boundary gas depleted reservoir that is refilled with CO_2, this curve calculation may be important. However, compressibility of gas and CO_2 and mixing and dissolution should be considered. In addition, clear thinking is needed to determine when the transition will take place. EGR will start the process of pressure increase and continue until gas recovery is not economic. A period of storage-only could follow. Because the gas trap is proven to hold buoyant fluid for geologic time, endangerment of USDW may not be relevant until the end of the project, when initial pressure is exceeded and fracture pressure is approached.
p. 26-27, section 3.2.	Suitability of Class II Area of Review Delineation	Improve discussion to explain how factors lead to non-suitable Area of Review	The suitability of the Class II AOR delineation is a logical trigger for the need for transition. Pragmatic guidance is needed for how to quickly assess fields under flood and determine if larger AOR and the multiphase modeling of Class VI is needed.
p. 27, para 3	EOR operations routinely use sophisticated computational modeling and uncertainty analysis to plan and evaluate the project, and this modeling	Not correct	Operators mostly run a ¼ pattern model or a few patterns or composition simulations. These models are usually set with mirroring boundary

	may be used to assess the adequacy of the current AoR delineation		conditions to save computation effort, and are by definition unsuitable for use in evaluation of the of the ¼ mile AOR. EPA needs to do new work to create a simple but robust test that can be used to determine if Class VI-type modeling is required.

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